What is claimed is:

[Claim 1] A method for analyzing distributed temperature data from a well, comprising:

obtaining temperature profile data along a portion of a wellbore;
providing the temperature profile data to a processor; and
automatically processing the temperature profile data to highlight valuable information to a user.

[Claim 2] The method as recited in claim 1, wherein automatically processing comprises removing noise from the temperature profile data.

[Claim 3] The method as recited in claim 1, wherein automatically processing comprises removing low order spatial trends.

[Claim 4] The method as recited in claim 1, wherein automatically processing comprises utilizing a high-pass filter.

[Claim 5] The method as recited in claim 1, wherein automatically processing comprises utilizing a low-pass filter.

[Claim 6] The method as recited in claim 1, wherein automatically processing comprises applying a model-fitting algorithm to the data.

[Claim 7] The method as recited in claim 6, wherein applying a model-fitting algorithm comprises selecting regions for fitting and fitting a model to data.

[Claim 8] The method as recited in claim 7, wherein applying a model-fitting algorithm further comprises testing results for statistical significance.

[Claim 9] The method as recited in claim 6, wherein applying a model-fitting algorithm comprises constructing a match filter and using extrema of a convolution of the filter with data to select candidate depths.

[Claim 10] The method as recited in claim 9, wherein constructing a match filter comprises incorporating modifications to the filter to make it orthogonal to background trends.

[Claim 11] The method as recited in claim 1, wherein automatically processing comprises trend removal and filtering of the temperature profile data.

[Claim 12] The method as recited in claim 1, wherein obtaining comprises utilizing a distributed temperature sensor.

[Claim 13] The method as recited in claim 1, wherein obtaining comprises deploying an optical fiber in the wellbore.

[Claim 14] The method as recited in claim 1, wherein obtaining comprises obtaining the temperature profile data with a temporary distributed temperature sensor installation.

[Claim 15] The method as recited in claim 1, wherein obtaining comprises obtaining the temperature profile data with a slickline distributed temperature sensing system.

[Claim 16] The method as recited in claim 1, wherein automatically processing comprises utilizing a match filter.

[Claim 17] The method as recited in claim 16, wherein the match filter is used to detect particular temperature signals corresponding to a particular downhole event.

[Claim 18] The method as recited in claim 17, wherein the downhole event comprises the location of a gas lift valve.

[Claim 19] The method as recited in claim 17, wherein the downhole event comprises a hole in a tubing.

[Claim 20] The method as recited in claim 17, wherein the downhole event comprises a leak in a wellbore completion tool.

[Claim 21] The method as recited in claim 1, wherein the automatically processing occurs in real-time with the obtaining data.

[Claim 22] A system to analyze distributed temperature data from a well, comprising:

a distributed temperature sensor adapted to measure temperature profile data along a portion of a wellbore;
a processor adapted to receive the temperature profile data; and
wherein the processor automatically processes the temperature profile data to highlight valuable information to a user.

[Claim 23] The system as recited in claim 22, wherein the distributed temperature system comprises an optical fiber.

[Claim 24] The system as recited in claim 22, wherein the distributed temperature sensor comprises an opto-electronic unit to launch optical pulses downhole.

[Claim 25] The system as recited in claim 24, wherein the opto-electronic unit is coupled to the processor by a communication link.

[Claim 26] The system as recited in claim 25, wherein the communication link comprises a hardline link.

[Claim 27] The system as recited in claim 25, wherein the communication link comprises a wireless link.

[Claim 28] The system as recited in claim 22, wherein the processor is embodied in a portable computer.

[Claim 29] The system as recited in claim 23, further comprising a production tubing deployed in the wellbore with the optical fiber.

[Claim 30] The system as recited in claim 29, wherein the production tubing is combined with a gas lift system.

[Claim 31] A method of detecting certain events within a well, comprising:

obtaining data over a period of time along a portion of a wellbore;

automatically processing the data to detect specific events related to heat energy in the well; and

displaying results to a user.

[Claim 32] The method as recited in claim 31, wherein obtaining data comprises obtaining temperature data along the portion of the wellbore.

[Claim 33] The method as recited in claim 32, wherein obtaining temperature data comprises utilizing a distributed temperature sensor.

[Claim 34] The method as recited in claim 31, wherein automatically processing comprises processing the data on a processor-based computer.

[Claim 35] The method as recited in claim 31, wherein automatically processing comprises processing backscattered light signals.

[Claim 36] The method as recited in claim 31, wherein automatically processing comprises applying a model-fitting algorithm to the data.

[Claim 37] The method as recited in claim 36, wherein applying a model-fitting algorithm comprises selecting regions for fitting and fitting a model to data.

[Claim 38] The method as recited in claim 37, wherein applying a model-fitting algorithm further comprises testing results for statistical significance.

[Claim 39] The method as recited in claim 36, wherein applying a model-fitting algorithm comprises constructing a match filter and using extrema of a convolution of the filter with data to select candidate depths.

[Claim 40] The method as recited in claim 39, wherein constructing a match filter comprises incorporating modifications to the filter to make it orthogonal to background trends.

[Claim 41] The method as recited in claim 31, wherein automatically processing comprises applying a phenomenological model to the data.

[Claim 42] The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to a particular downhole event.

[Claim 43] The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to location of a gas lift valve.

[Claim 44] The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to a wellbore completion tool leak.

[Claim 45] The method as recited in claim 31, wherein automatically processing comprises detecting particular temperature signals corresponding to a hole in a production tubing.

[Claim 46] The method as recited in claim 31, wherein displaying comprises displaying results in graphical form on a display monitor.

[Claim 47] The method as recited in claim 31, wherein automatically processing comprises utilizing a match filter.

[Claim 48] The method as recited in claim 31, wherein automatically processing occurs real-time with the obtaining data.

[Claim 49] A method of determining a flow rate, comprising:

providing a well model relating temperature characteristics to a flow rate of a production fluid in a well having a gas lift system;
measuring temperatures along the well; and
determining the flow rate based on applying the well model to measured temperature data.

[Claim 50] The method is recited in claim 49, wherein determining comprises determining the flow rate based on a decay length of a thermal perturbation at a gas injection location.

[Claim 51] The method as recited in claim 49, wherein determining comprises determining the flow rate based on a measured amplitude of a thermal discontinuity at a gas injection location.

[Claim 52] The method as recited in claim 49, further comprising estimating the heat capacity of the production fluid and using the heat capacity estimate in the well model.

[Claim 53] A method, comprising:

measuring a temperature profile in a well having a gas lift system to produce a fluid through a production tubing; and
determining a flow rate through the production tubing based solely on the temperature profile and established well parameters.

[Claim 54] The method as recited in claim 53, further comprising obtaining the established well parameters.

[Claim 55] The method as recited in claim 54, wherein obtaining comprises establishing a heat capacity of the fluid.

[Claim 56] The method as recited in claim 54, wherein obtaining comprises establishing a radial heat transport value in the well.

[Claim 57] The method as recited in claim 54, wherein obtaining comprises establishing a thermal conductivity of a surrounding well formation.

[Claim 58] The method as recited in claim 54, wherein obtaining comprises establishing a thermal history of the well.

[Claim 59] The method as recited in claim 53, wherein measuring comprises measuring the temperature profile with a distributed temperature sensor.

[Claim 60] The method as recited in claim 53, wherein determining comprises determining the flow rate based on a decay length of a thermal perturbation at a gas injection location.

[Claim 61] The method as recited in claim 53, wherein determining comprises determining the flow rate based on a measured amplitude of a thermal discontinuity at a gas injection location.

[Claim 62] The method as recited in claim 53, further comprising processing the temperature profile according to a stored model relating the temperature profile to the flow rate.

[Claim 63] A method of determining a flow rate, comprising:

providing a well model relating flow rate of a production fluid to a decay length of a thermal perturbation at a gas injection location;
measuring temperatures along the well; and

applying the well model to the measured temperatures to determine the flow rate based on the decay length of the thermal perturbation.

[Claim 64] The method as recited in claim 63, wherein providing comprises developing the well model to utilize a heat capacity of the production fluid.

[Claim 65] The method as recited in claim 63, wherein providing comprises developing the well model to utilize a radial heat transport value of the well.

[Claim 66] The method as recited in claim 63, wherein providing comprises developing the well model to utilize a thermal conductivity of a surrounding formation.

[Claim 67] The method as recited in claim 63, wherein providing comprises developing the well model to utilize a thermal history of the well.

[Claim 68] A method of determining a flow rate, comprising:

providing a well model relating flow rate of a production fluid to a measured amplitude of a thermal perturbation at a gas injection location;
measuring temperatures along the well; and
applying the well model to the measured temperatures to determine the flow rate based on the measured amplitude of the thermal perturbation.

[Claim 69] The method as recited in claim 68, wherein providing comprises developing the well model to utilize a heat capacity of the production fluid.

[Claim 70] The method as recited in claim 68, wherein providing comprises developing the well model to utilize a pressure drop between an annulus and a production tubing.

[Claim 71] The method as recited in claim 68, wherein measuring comprises utilizing a distributed temperature sensor.

[Claim 72] The method as recited in claim 68, wherein applying comprises applying the well model to the measured temperatures on a processor system.

[Claim 73] A system, comprising:

a temperature sensor system deployed with a gas lift system in a well to measure temperature in a plurality of locations along the well; and
a processor system able to receive the measured temperatures and apply the measured temperatures to a stored model, the stored model being able to establish a fluid flow rate of a produced fluid based on a thermal perturbation at a gas injection location of the gas lift system.

[Claim 74] The system as recited in claim 73, wherein the temperature sensor system comprises a distributed temperature sensor.

[Claim 75] The system as recited in claim 73, wherein the stored model establishes the fluid flow rate based on a decay length of the thermal perturbation.

[Claim 76] The system as recited in claim 73, wherein the stored model establishes the fluid flow rate based on a measured amplitude of the thermal perturbation.

[Claim 77] The system as recited in claim 73, wherein the well model utilizes an established well parameter to improve the accuracy of the determined fluid flow rate for a given well.

[Claim 78] The system as recited in claim 77, wherein the established well parameter comprises a heat capacity of the produced fluid.

[Claim 79] The system as recited in claim 77, wherein the established well parameter comprises a radial heat transport value of the well.

[Claim 80] The system as recited in claim 77, wherein the established well parameter comprises a thermal conductivity of a surrounding formation.

[Claim 81] The system as recited in claim 77, wherein the established well parameter comprises a thermal history of the well.

[Claim 82] A system, comprising:

means for measuring a temperature profile in a well having a gas lift system to produce a fluid through a production tubing; and
means for determining a flow rate through the production tubing based solely on the temperature profile and established well parameters.

[Claim 83] The system as recited in claim 82, wherein the means for measuring comprises a distributed temperature sensor.

[Claim 84] The system as recited in claim 82, wherein the means for determining comprises a model relating a thermal perturbation to a flow rate of the fluid.

[Claim 85] A method of determining a flow rate, comprising:

providing a well model relating temperature characteristics to a flow rate of a production fluid in a well;

measuring temperatures along the well; and
determining the flow rate based on applying the well model to measured temperature data.

[Claim 86] A method, comprising:

measuring a temperature profile in a well having a gas lift system to produce a fluid through a production tubing;
determining a flow rate through the production tubing based on the temperature profile and established well parameters; and
automatically optimizing the flow rate.

[Claim 87] The method as recited in claim 86, wherein measuring comprises measuring the temperature profile with a distributed temperature sensor.

[Claim 88] The method as recited in claim 86, wherein automatically optimizing comprises changing a gas injection rate.

[Claim 89] The method as recited in claim 86, wherein determining comprises determining the flow rate based on a decay length of a thermal perturbation at a gas injection location.

[Claim 90] The method as recited in claim 86, wherein determining comprises determining the flow rate based on a measured amplitude of a thermal discontinuity at a gas injection location.

[Claim 91] A system, comprising:

a distributed temperature sensor deployed with a gas lift system in a well to obtain a temperature profile along the well; and
a processor system able to receive the measured temperatures and apply the measured temperatures to a stored model, the stored model being able to

establish a fluid flow rate of a produced fluid and to automatically optimize the fluid flow rate.

[Claim 92] The system as recited in claim 91, wherein the stored model establishes the fluid flow rate based on a decay length of a thermal perturbation along the gas lift system.

[Claim 93] The system as recited in claim 91, wherein the stored model establishes the fluid flow rate based on a measured amplitude of a thermal perturbation along the gas lift system.

[Claim 94] The system as recited in claim 91, further comprising utilizing an established well parameter to improve the accuracy of the fluid flow rate determined for a given well.